Montana – Dakotas Regional Transmission Study

WEST SIDE STUDIES
PROJECT 1

Western
AREA POWER
ADMINISTRATION

UPPER GREAT PLAINS REGION
Transmission Planning

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PROJECT 1 SUMMARY

A 1000 MW generation facility was modeled near the existing plant at Colstrip, Montana. Four separate transmission line routes at 230 kV and 500 kV voltage classes were considered to provide export capability for the new generation. Import areas studied included Spokane (NORTHWEST), North Lethbridge (ALBERTA), Salt Lake City (PACE), and Denver (PSCOLORADO). In most cases, the transmission line route under study was a radial line from the location of the new generation to the load center. In two cases, the Salt Lake City load center was indirectly served by a line routed to Spokane or to Denver respectively.

For each transmission line and schedule combination, the impact of the added facilities on the existing system was gauged in terms of the merged NERC/WECC Planning Standards. The Project caused an overall increase in power losses for all cases. The smallest increase in real power losses occurred for the Line 3 case with schedule to Denver. Reactive power margins were severely reduced for Line 1 cases. Line 4 provided the most significant improvement in reactive power losses.

System Intact rating and voltage violations were found primarily for Line 1 and Line 4 scenarios. Improvements to system rating and voltage violations were minimal in all cases. Additional loading was observed on the existing 500 kV corridor from Colstrip to Garrison with all line and schedule combinations. This confirms that the existing system, with the two transmission alternatives to upgrade the Hiline system, does not provide adequate capacity for the successful integration of 1000 MW of new generation into the Montana system.

Results of contingency analysis show that Line 3 scheduled to Denver created the least number of Category B violations. Contingencies on sections of the Project lines caused the majority of violations, and in some cases resulted in a non-converging model, indicating that some of the new line sections are essential paths for the flow of new generation. Analysis of the 230 kV upgraded Hiline (Project 1, Line 1) produced a large number of severe Category A and Category B violations, indicating that it is not a feasible solution for transporting large amounts of new generation.

In general, contingencies near the load centers reflect the heavy flows introduced by the Project Lines 2 and 3. Existing 230 kV facilities at Bell Substation near Spokane and at Daniels Park near Denver may experience overloads for certain contingencies. Line 3 and Line 4 increased the susceptibility to overloads of the Anaconda-Amps-Antelope 230 kV line and the adjacent Anaconda-Dillon-Jefferson 161 kV line during contingencies. The existing constraint along the Utah-Colorado border was overloaded for schedules to Salt Lake City and contingencies on the Bonanza-Mona 345 kV line. Line 3 increased violations for the Bonanza-Mona outage, whereas violations were alleviated with the addition of Line 4.

The stability of two generating stations was compromised by the Project. The affected units were Kerr and Fort Peck during fault scenarios conducted on models containing Line 1 or Line 4. The system was shown to be transiently stable otherwise. Three post-transient voltage violations occurred during one fault scenario on the upgraded 230 kV Hiline (Line 1). Lines 2 and 3 improved system stability over the pre-Project case.

Line 1 represents the least in cost of the Project lines estimated at $160 million. The realization of Line 4 is most expensive at $645 million. Cost estimates for Lines 2 and 3 are $392 million and $369 million respectively.

An evaluation of each of the analyses was completed to determine the overall feasibility of each of the transmission alternatives. Table 10 summarizes these conclusions. The most viable transmission line options studied for Project 1 are Line 2 to Spokane and Line 3 to Denver. System intact and stability was acceptable for these two line options. Contingencies which were impacted by the Project are localized to the delivery points of the new lines. The specific impacts, summarized in the Appendices for the two viable transmission options, would need to be addressed during project development in terms of the recommended solutions.

1. INTRODUCTION AND PROJECT SCOPE

Project 1 of the Montana Transmission Study investigates the effects of a power plant near Colstrip, Montana. Several 500 kV transmission line routes to deliver power to remote load centers were considered.

1.1 Scope

The Project simulated a 1000 MW Coal-fired generation plant located on a 40 mile double-circuit tap to the existing Colstrip 500 kV bus. The following transmission alternatives were investigated with corresponding load flow schedules. For the purpose of discussion, each alternative is referred to as “Line 1”, “Line 2”, “Line 3”, and “Line 4” hereafter.

Line 1: 230 kV line from Colstrip to Fort Peck, Montana; upgrade existing line from Fort Peck to Great Falls from 161 kV to 230 kV

- Scheduled to Spokane
- Scheduled to Salt Lake City

Line 2: 500 kV line from Colstrip, Montana to Spokane, Washington

- Scheduled to Spokane

Line 3: 500 kV line from Colstrip to Denver, Colorado

- Scheduled to Denver
- Scheduled to Salt Lake City

Line 4: 230 kV line from Colstrip to Fort Peck; upgrade existing line from Fort Peck to Great Falls from 161 kV to 230 kV; 500 kV line from Lethbridge, Alberta to Salt Lake City.

- Scheduled to Salt Lake City
- Scheduled to Lethbridge

Project maps illustrating the line routing for each of the transmission alternatives can be found in the Appendices. Figure 1 illustrates the line routing for Line 1. The Project generator is located near the existing Colstrip plant, and is tied into the existing 500 kV bus at Colstrip via a double circuit tap 40 miles in length. From the existing 230 kV bus at Colstrip, a single circuit 230 kV line is routed north to Fort Peck. Next, the existing transmission path from Fort Peck to Havre, known as the Hiline, is upgraded to operate at 230 kV. The final section of Line 1 replaces the existing 161 kV lines from Havre to Great Falls.

Figure 2 presents the route for Line 2. A new 500 kV line parallels the existing 500 kV corridor from Colstrip to Broadview to Garrison. From Garrison, Line 2 continues northwest to Hot Springs and on to Bell near Spokane, Washington.

In Figure 3, the path is demonstrated for Line 3. The 500 kV line extends from Colstrip to Dave Johnston power plant in Wyoming to Daniels Park Substation south of Denver, Colorado.

Figure 4 illustrates line routing for Line 4. Line 4 duplicates the 230 kV route of Line 1 and adds a 500 kV line from Lethbridge, Alberta to Ben Lomond Substation near Salt Lake City Utah. The 500 kV line ties to the existing system at Lethbridge, Great Falls, Dillon, Kinport, and Ben Lomond.

2. DESCRIPTION OF THE BASE CASES

Two models obtained from the WECC were used to build the Project models. From these models, seven additional system models were established in order to study and compare the different combinations of transmission lines and schedules. In all cases, the additional Project generation was scheduled by reducing generation in the destination area.

2.1 Line 1 Scheduled to Spokane

The Spokane Line 1 model represents the Project generator scheduled to the Spokane area. It is based on the WECC 2002 Light Summer model, which represents anticipated heavy flows from Montana to Washington. Area schedules were modified to reflect 900 MW of additional export from Montana, and 900 MW of additional import to Northwest. Note that although the Project 1 generator produces 1000 MW of additional power, the actual schedule between the Montana and Northwest areas is to be 900 MW. This is done in order to minimize changes to the swing generators located in each area that absorb the system losses. The difference between the Project-supplied power and scheduled power gives an approximation of the real power losses of the new line with the schedules. A more detailed analysis of system losses is presented in Section 3.1.

Shunt capacitors of 600 MVAR and 400 MVAR were added on existing 500 kV buses at Broadview and Taft respectively in order to maintain nominal 500 kV voltage levels.

2.2 Line 1 Scheduled to Salt Lake City

The second model represents Project generation scheduled to Salt Lake City with Line 1 in service. It is based on the WECC 2002 Heavy Summer model. Of the 1000 MW of new Project generation added to the system, 880 MW was scheduled to the Salt Lake City area with minimal impact on swing generators. Shunt capacitors of 500 MVAR and 200 MVAR were added at Broadview 500 kV and Taft 500 kV buses respectively to provide voltage support.

2.3 Line 2 Scheduled to Spokane

The next model represents the Project generation scheduled to Spokane with Line 2 in service. Static VAR Compensators (SVC's) were added to the Broadview 500 kV and Garrison 500 kV buses in order to compensate for line charging of Line 2. This model is based on the WECC 2002 Light Summer model. All 1000 MW of Project generation was scheduled to the Northwest area.

2.4 Line 3 Scheduled to Denver

Based on the WECC 2002 Heavy Summer case, this model simulates power scheduled to Denver with Line 3 in service. SVC's were added to the Colstrip 500 kV bus and the new 500 kV bus at Dave Johnston. It was possible to schedule all 1000 MW of the Project generation to the Denver area without negatively impacting swing generation.

2.5 Line 3 Scheduled to Salt Lake City

With Line 3 in service, Project generation was also scheduled to Salt Lake City. Added SVC's are identical to those added for Line 3 scheduled to Denver. A schedule of 1000 MW was achieved with minimal effect on the swing generators. This model is based on the WECC 2002 Heavy Summer model.

2.6 Line 4 Scheduled to Salt Lake City

For Line 4, the model is based on the WECC 2002 Heavy Summer model. Project generation was scheduled to the Salt Lake City area. SVC's were located along Line 4 at Lethbridge, Great Falls, Dillon, Kinport, and Ben Lomond in order to regulate bus voltage. A schedule of 850 MW was achieved from the total 1000 MW of added generation.

2.7 Line 4 Scheduled to Lethbridge

The last model is of the Project scheduled to Lethbridge with Line 4 in service. SVC's added are identical to those found in the Line 4 model scheduled to Salt Lake City. A schedule of 845 MW was applied. The model is based on the WECC 2002 Heavy Summer case.

3. POWER FLOW ANALYSIS

Two power flow conditions were studied: Category A and Category B. The effect of the Project was gauged by comparing Pre-Project and Post-Project rating and voltage violations. Additionally, power losses were studied for Category A conditions.

3.1 Category A Power Losses

Table 1 summarizes the change in system losses due to the Project. Losses are sorted by area, and are broken up into real power (MW) and reactive power (MVAR) losses. Please note that only those areas with significant changes are included in Table 1. Positive values in the table indicate an increase in system losses, whereas negative values indicate that losses decreased. Values in bold text indicate the area to which the Project has been scheduled. For example, Spokane is located in the Northwest area, and Salt Lake City is within the PACE area.

Table 1 - Project Effect on System Losses by Area

Line Code -->	L1		L1		L2		L3		L3		L4		L4	
Schedule -->	Spokane		Salt Lake City		Spokane		Denver		Salt Lake City		Salt Lake City		Lethbridge	
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR
Total System	166	1660	241	2349	114	-189	42	-352	103	194	99	-888	45	-1417
Northwest	**52**	**356**	93	1196	**50**	**-317**	9	109	29	450	3	-11	-57	-790
B.C. Hydro	7	46	5	52	10	78	1	20	1	15	0	7	16	296
Alberta	0	0	0	0	0	0	0	0	0	0	8	-469	**-22**	**-751**
Idaho	6	58	-18	-269	3	30	-1	-6	-19	-236	-36	-362	-1	33
Montana	92	1168	102	1068	50	-1	39	30	60	177	139	501	125	291
WAPA U.M.	3	-37	6	12	0	1	0	8	0	0	10	32	10	24
PACE	3	30	**40**	**237**	0	6	0	-9	**50**	**452**	**-25**	**-567**	-29	-543
Colorado	1	4	0	-6	0	2	**-6**	**-496**	-28	-816	0	-4	1	5
WAPA R.M.	3	38	15	70	1	16	-1	-6	10	156	4	1	2	24

All Project lines result in increased active power (MW) losses overall. In terms of the added 1000 MW of generation at Colstrip, anywhere from 4% to 24% can be attributed to real power losses. Table 1 indicates that heavy reactive losses are incurred for Line 1, resulting in lower reactive power (VAR) margins. Inadequate VAR margins can cause poor system performance to disturbances. The case for Line 3 with schedule to Salt Lake City also shows increased VAR losses.

3.2 Category A Violations

Table 2 presents the number of Category A rating and voltage violations which were affected by the Project. The first results column gives the number of violations caused or worsened by the Project. The second results column gives violations which were fixed or improved by the Project.

Table 2 - Category A Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	2	2	2	1
		B.C.Hydro	-	3	-	-
		Montana	1	-	-	-
		WAPA U.M.	-	3	-	-
	Salt Lake City	Northwest	-	-	-	1

		B.C.Hydro	-	3	-	7
		Montana	-	8	-	1
		WAPA U.M.	-	3	-	-
		PACE	-	11	-	2
L2	Spokane	Northwest	-	2	2	2
		B.C.Hydro	-	3	-	-
		Montana	-	-	-	1
L3	Denver	Northwest	-	-	-	2
		B.C.Hydro	-	-	-	7
		Montana	-	-	-	1
	Salt Lake City	Northwest	-	-	-	3
		B.C.Hydro	-	-	-	2
		Montana	-	2	-	1
		PACE	3	1	-	2
L4	Salt Lake City	Northwest	-	1	-	-
		B.C.Hydro	-	7	-	1
		W.Kootenay	-	2	-	4
		Montana	1	-	-	1
		PACE	-	1	-	1
	Lethbridge	Northwest	-	1	-	2
		B.C.Hydro	3	19	-	0
		W.Kootenay	-	6	-	-
		Alberta	1	18	2	14
		Montana	2	-	-	1
		PACE	-	-	-	2

3.2.1 Line 1

Three Category A rating violations are caused by the Project for Line 1. The double circuit Garrison to Taft 500 kV transmission line became overloaded by 18% of its full load rating of 993 MVA per circuit. The overload on the Garrison-Taft 500 kV circuits is due to the fact that Line 1 does not carry a sufficient volume of the new Project generation. Power flow from Colstrip to Fort Peck is 72 MW, or 8% of the schedule to Spokane. The existing 500 kV corridor from Colstrip to Taft provides the best path for the additional power. The addition of a phase shifting transformer, while not evaluated in this study, could be used to direct the flow across the Hi Line and should be the basis of future analysis of this transmission option. This addition would not necessarily provide the needed increase in system transfer capability, but may eliminate some of the very heavy overloads.

The third overload occurred on the Generator Step Up (GSU) transformer of existing Colstrip Unit 4. This overload is due to the increase in VARs being supplied by the generator.

It is readily apparent that the addition of Line 1 to the system cannot support 1000 MW of new generation at Colstrip, particularly for schedules to Spokane. Even though the schedule to Salt Lake City did not introduce any new Category

A rating violations, existing lines are loaded to the point that the system cannot properly manage contingency conditions, as will be discussed in Section 3.3.1.

3.2.2 Line 2 Scheduled to Spokane

With Project generation scheduled to Spokane, Line 2 did not create any rating violations. Voltages were raised to just over 1.05 pu on two 230 kV buses in the Northwest area: Hot Springs and Cascade. Pre-Project voltage on these buses was 1.02 pu and 1.05 pu respectively. Similar changes occurred on two 500 kV buses and one 230 kV bus in British Columbia.

Two rating violations in the Northwest area are eliminated with this option. The two "CHIEFJO" GSU transformers experience 20% decreases in their loading. This decrease is due to a reduction of generator output due to the scheduling method, and can not be considered an improvement brought about by the Project. Three overvoltage violations (1.05 pu) were slightly reduced on the 115 kV system at ANA BPA, HANLY R1, and RINGOLD.

3.2.3 Line 3 Scheduled to Denver

No Category A violations were caused by the Project Line 3 with schedule to Denver. Ten overvoltages ranging from 1.05 pu to 1.06 pu were brought just below the 1.05 pu threshold on 230 kV, 132 kV, and 115 kV systems. Due to the distance of these "improvements" from Line 3, they are insignificant.

3.2.4 Line 3 Scheduled to Salt Lake City

Three rating violations are present in the PACE area for this line and schedule combination. Because of Line 3 routing to Denver, overloads occur in two areas which are known to be transfer constraints: Amps and Bonanza. The first rating violation is located in western Idaho. The Jefferson 161 kV phase-shifting transformer loading increases from 87% to 114% of its 100 MVA rating. The second violation, line Bonanza-Mona 345 kV, traverses the Colorado-Utah border, and is at 121% of its 650 MVA rating.

Undervoltage violations begin to appear on buses at Peterson Flats 230 kV (0.94 pu), Dillon 161 kV (0.94 pu), and Big Grassy 161 kV (0.93 pu), which are all located in the vicinity of the Amps constraint. Two other reductions in voltage occur on the 500 kV system at Garrison and Bell BPA, indicating decreased voltage support. Nominal voltage at Garrison 500 kV and Bell 500 kV is 1.08 pu. Table 3 shows the change in voltage levels for these two buses. For this scheduled case, voltages at Garrison and Bell BPA are 3% to 5% below nominal.

Table 3 - 500 kV Category A Voltages; Line 3 Scheduled to Salt Lake City

500 kV Bus	Nominal Voltage	Pre-Project Voltage	Post-Project Voltage (Line 3, scheduled to Salt Lake City)	Percent Change	Percent Difference from Nominal
Garrison	1.080 pu	1.078 pu	1.047 pu	-2.9%	-3.0%
Bell BPA	1.080 pu	1.067 pu	1.026 pu	-3.8%	-5.0%

Improvements to the system with Line 3 scheduled to Salt Lake City are trivial. As was the case for Line 3 scheduled to Denver, bus voltages lying just outside the criteria have been slightly improved to within 5% of nominal.

3.2.5 Line 4 Scheduled to Salt Lake City

With Line 4 in service to Salt Lake City, one new Category A rating violation occurred for a schedule to the same location. The Anaconda-Dillon 161 kV line reached 114% of its 165 MVA rating. New voltage violations represent minor changes to 138 kV, 161 kV, and 500 kV systems in Canada. In the PACE area, an overvoltage of 1.06 pu developed on Swan Valley 161 kV near the Goshen bus in Idaho. Seven minor reductions in overvoltage violations were observed in Canada, Montana, and PACE.

The 500 kV system in Montana was impacted for this line and schedule combination. Buses at Broadview, Garrison, and Bell all demonstrate reduced voltage that would have to be addressed. Table 4 summarizes these changes.

Table 4 - 500 kV Category A Voltages; Line 4 Scheduled to Salt Lake City

500 kV Bus	Nominal Voltage	Pre-Project Voltage	Post-Project Voltage (Line 3, scheduled to Salt Lake City)	Percent Change	Percent Difference from Nominal
Broadview (1 and 2)	1.080 pu	1.074 pu	1.042 pu	-3.0%	-3.5%
Garrison	1.080 pu	1.078 pu	1.035 pu	-3.9%	-4.1%
Bell BPA	1.080 pu	1.067 pu	1.048 pu	-1.7%	-3.0%

3.2.6 Line 4 Scheduled to Lethbridge

Scheduling power flow to Lethbridge created four new overloads in Canada and two in Montana. The overloads in Canada indicate that the schedule is primarily being met by interchanges between the B.C. Hydro and Alberta areas. Facilities at Natal, which is near the B.C.-Alberta border, reach load levels of up to 105% versus base case loading of 52%. In contrast, the Line 4 section from Great Falls to Lethbridge carries only 270 MW or 21% of its rating from Montana into Alberta. A phase shifting transformer could be utilized to direct more flow northward, but may cause additional overloads in the Alberta area. The Colstrip Unit 4 GSU also became overloaded by 3% due to increased VAR output. This overload could be addressed by adding additional shunt compensation to the system in place of the unit VAR output.

Numerous voltage violations developed in Canada, the majority of which were overvoltages ranging from 1.05 pu to 1.06 pu. The worst overvoltage occurred on bus “KCL230” 230 kV near Selkirk. Its voltage increased from a base case level of 1.05 pu to 1.09 pu. One undervoltage of 0.92 pu was observed at bus Natal 230 kV. As with the previous cases, voltage improvements indicated in Table 2 are minimal.

3.3 Category B Violations

Table 5 introduces the number of violations affected by the project for Category B Power Flow. Approximately 1,949 single-outage contingencies were analyzed for each schedule. The number of contingencies varies slightly based on which Project line is in service.

Note that Table 5 is only relevant to continuous ratings (Rate 1).

Table 5 - Category B Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	28	85	-	1
		Montana	2	47	2	-
		WAPA U.M.	-	1	-	-
		WAPA R.M.	1	6	-	-
	Salt Lake City	Northwest	24	52	3	-
		Idaho	4	2	4	2
		Montana	7	50	-	6
		WAPA U.M.	1	9	-	-
		PACE	7	24	3	8
		WAPA R.M.	12	20	4	2
L2	Spokane	Northwest	30	76	-	-
		Montana	-	1	2	-
		WAPA R.M.	1	4	-	-
L3	Denver	Northwest	1	3	-	-
		Montana	2	9	-	-
		PACE	1	-	2	2
		Colorado	7	-	6	31
		WAPA R.M.	4	3	6	5
	Salt Lake City	Northwest	4	8	2	-
		Idaho	1	1	4	2
		Montana	5	7	-	2
		PACE	16	39	1	1
		Colorado	5	1	9	38
		WAPA R.M.	20	32	5	9
L4	Salt Lake City	Northwest	7	14	4	-
		Idaho	-	1	4	2
		Montana	8	57	-	-
		WAPA U.M.	-	12	-	-
		PACE	3	6	19	10
		WAPA R.M.	7	7	1	4
	Lethbridge	Northwest	7	7	15	8
		Idaho	-	-	3	1
		Montana	7	45	-	3
		WAPA U.M.	-	11	-	-
		PACE	2	2	20	19
		WAPA R.M.	2	2	1	3

3.3.1 Line 1

Table 5 illustrates extensive Category B rating and voltage violations for Line 1 regardless of the schedule. Loading levels are as high as 214% on sections of the 500 kV system in western Montana. These findings are consistent with results for Category A conditions, as discussed previously in Section 3.2.1. Because of the fact that the 230 kV Project Line 1 is not adequate for the additional power flow from Colstrip, existing transmission facilities develop acute overloads and severe undervoltage violations for Category B conditions, particularly for outages along the 500 kV corridor from Colstrip to the state of Washington.

It is not necessary to discuss the violations in detail for Line 1. Their quantity and severity confirms that Line 1 is not a viable system improvement to support significant increases in generation in eastern Montana.

3.3.2 Line 2 Scheduled to Spokane

Category B violations for Line 2 with schedule to Spokane indicate heavy loading of the Bell substation. In particular, when the Dworshak to Taft 500 kV line is out of service, two rating violations occur on transformers at Bell. The first is the “BELL BPA” to “BELL SO” 500-230 kV transformer which reaches 150% of its 1220 MVA continuous rating. The second rating violation occurs on the “BELL MI” to “BELL BPA” 230-115 transformer which is rated at 249 MVA continuous. Its base case loading was 95%, and its post-Project loading increases to 112%. Seven additional rating violations at Bell substation or at nearby Beacon occurred for other contingencies, and ranged from 143% to 107%.

A 6% reduction in voltage occurred on the “BELL BPA” 500 kV bus for contingency Dworshak to Taft 500 kV. Table 6 weighs the change in voltage between base case WECC model and the Project-scheduled model for this contingency.

Table 6 - Voltage Comparison: BELL BPA 500 kV

Bus	Model	Pre-contingency Voltage (pu)	Voltage (pu) for Contingency Dworshak - Taft 500 kV	Percent Change
BELL BPA 500 kV	WECC 2002 Light Summer (pre-Project)	1.051	1.013	-3.6%
	Line 2 Scheduled to Spokane (post-Project)	1.091	1.025	-6.6%
Percent Change		3.8%	1.2%	

The second row of Table 6 shows that the post-Project voltage during this contingency was 1.03 pu versus 1.09 pu in the pre-contingency case. In the pre-Project model (first row) however, the voltage at “BELL BPA” 500 kV was 1.01 pu for this same contingency. Table 6 illustrates that the Project results in a greater overall change in voltage for the contingency, but a slightly less severe undervoltage as opposed to the pre-Project case.

The remaining voltage violations in the Line 2 model scheduled to Spokane total 76 in the Northwest area. All of them are undervoltages on 230 kV and 115 kV buses, and occur for two contingencies near Dworshak: Dworshak to Taft 500 kV, and Dworshak to Hatwai 500 kV. The worst undervoltage is 0.92 pu at the Ralston 115 kV bus located near Lind, Washington. These results are consistent with previously identified constraints and suggest that additional outlet transmission will be required to fully integrate the proposed generation into the system.

No Category B voltage violations were fixed or improved by the Line 2 model, as indicated by Table 5; however, two rating violations were corrected. Series capacitors are present on the existing double circuit 500 kV line at Broadview substation. The model indicates that the series capacitors on one circuit become overloaded to 103% for an outage on the parallel circuit between Colstrip and Broadview. The introduction of Line 2 eliminates this overload, bringing the loading on the series capacitors to down to 81% during the outage.

3.3.3 Line 3 Scheduled to Denver

Table 5 presents a total of 15 new Category B rating violations with Line 3 scheduled to Denver. Seven violations are located in the Denver area, and four are in Western's Rocky Mountain area. Overloads as high as 108% to near-overloads of 95% occurred on 230 kV and 115 kV lines that tie to Daniels Park Substation. The most severe overload occurred during a contingency of Line 3 section Dave Johnston to Daniels Park 500 kV. The 230 kV circuit from Dave Johnston to Laramie River Station became overloaded by 51% of its 266 MVA rating. Additionally, the STEGALDC to STEGALL 230 kV line reached 103% of its 150 MVA load for the same Line 3 contingency.

Overload levels increased on parallel 230-115 kV transformers at Smoky Hill and Waterton (circuits 1 and 2) for contingencies on the adjacent transformer. Pre-project loads of 99% to 104% increased by an additional 13% to 20% with the introduction of the Project, indicating that these transformers are not capable of handling new Project loading for extended outages.

Fifteen undervoltage violations developed under Category B conditions. Most of these violations are minimal: between 0.938 pu and 0.949 pu on 115 kV, 161 kV, and 230 kV buses.

Table 5 also shows that Line 3 provides relief to several 115 kV and 230 kV systems in Colorado and southeastern Wyoming. For example, during the Bonanza to Mona 345 kV line outage, overloading on the two 230-138 kV transformers at Flaming Gorge is reduced from 116% to 109%.

All of the Category B voltage violations which are reported as fixed for this line and schedule combination are relatively trivial. The lowest pre-Project voltage of 0.935 pu was on the Marcy 230 kV bus for an outage on the 230 kV line from

Marcy to Daniels Park. Post-Project voltage at Marcy 230 kV for the same contingency was 0.953 pu.

3.3.4 Line 3 Scheduled to Salt Lake City

Scheduling additional power flows to the Salt Lake City area with Line 3 routed to Denver produced numerous Category B violations, mainly in the PACE and WAPA R.M areas. The increased flows which developed on existing transmission in Montana, Idaho, and Colorado cannot be supported during specific contingencies. Near-overload conditions (95% to 99% of ratings) were produced on the 161 kV system which parallels the 230 kV route from Anaconda to Antelope.

In Montana, the existing 500 kV double circuit corridor experienced rating violations for certain contingencies. The series capacitors at Broadview (rated at 1732 MVA) became 8% overloaded for outages on the two Colstrip to Broadview 500 kV circuits. A single-circuit outage between Garrison 500 kV and Taft 500 kV (rated at 944 MVA) caused a 15% overload on the adjacent circuit.

Serious rating violations were located along the Utah-Colorado border during contingencies on the 345 kV line from Bears Ears to Bonanza to Mona. The 138 kV system in this area provides the transfer path for power flows from Colorado to Utah when sections of the 345 kV line are out of service. Hayden to Artesia 138 kV reaches 163% of is 90 MVA rating for contingency Bears-Bonanza 345 kV. Two 230-138 kV transformers at Flaming Gorge experienced a 32% increase in their 100 MVA ratings during the Bonanza-Mona 345 kV line outage. Five other rating violations ranging from 146% to 99% developed on the 138 kV system, and eight more were made worse by 5% to 29%.

During contingency analysis, the Project model failed to converge for several line outages of significance. Table 7 presents the non-converged outages that are a result of the Project.

Table 7 - Non-converged Outages for Line 3 Scheduled to Salt Lake City

Contingency	Rating at Operating Voltage (MVA)	Line Load (pre-contingency) (MVA)	Percent Load of Rating	Pre-Project Percent Load of Rating
Dave Johnston - Colstrip 500 kV (section of Line 3)	1764	750	43%	N/A
Anaconda - Peterson Flats 230 kV	478	280	59%	49%
Amps - Antelope 230 kV	439	224	51%	42%
Bears Ears - Craig 345 kV	1763	607	34%	20%
Emma Park - Upalco 138 kV	135	126	93%	74%

The non-converged outages in Table 7 coincide with either the Project Line 3 or areas of power flow constraint. With the Line 3 section from Dave Johnston to Colstrip out of service, the surrounding system is unable to adequately support the Project generation. Similarly, the Anaconda-Peterson Flats and the Amps-Antelope outages create additional strain on the power flow paths from southwestern Montana through Idaho. Power flow paths from Colorado to Utah exhibit comparable problems, where outages of Bears Ears - Craig 345 kV and Emma Park - Upalco 138 kV failed to converge.

The location of Category B voltage violations are consistent with the locations of the rating violations caused by the Project. The majority of undervoltages (53 of 88) occurred during the Bonanza-Mona 345 kV line outage. The 13 most severe of these undervoltages occurred on the 138 kV system near Bonanza in the PACE area, and ranged from 0.89 pu to 0.81 pu. Two 345 kV buses, Grand Junction and Montrose, also exhibited voltage violations during this contingency, dropping from 0.99 pu to 0.92 pu.

The 500 kV Line 3 bus at Daniels Park exhibited an undervoltage of 0.99 pu from 1.06 pu during contingency Dave Johnston-Daniels Park 500 kV. The majority of remaining undervoltage violations range from 0.92 pu to 0.949 pu on 230 kV, 138 kV and 115 kV systems in the PACE and WAPA R.M. areas.

Rating and voltage violations that are reported in Table 5 as fixed or improved by the Project are relatively minor when compared to the number of new violations that were created. The majority of improvements occurred in the Denver area during nearby contingencies. Similar to the improvements discussed in Section 3.3.3 above, the presence of Line 3 alleviates the effect of surrounding outages on the system.

3.3.5 Line 4 Scheduled to Salt Lake City

A comparison of all three schedules to Salt Lake City listed in Table 5 reveals that Line 4 causes the fewest number of new Category B violations. Severe overloads occurred on the 161 kV line from Anaconda to Dillon, and from Dillon to Big Grassy during contingencies on both Line 3 sections that tie into the Dillon substation. A Line 3 connection to nearby Peterson Flats 230 kV bus instead of Dillon 161 kV would alleviate the overloads on the 161 kV system; however, similar overloads would develop along the 230 kV Anaconda-Peterson Flats-Amps route.

The existing 500 kV double circuit transmission lines in Montana also experienced Category B overloads due to the Project, indicating that the Project generation at Colstrip exports mainly to the Northwest area, while the scheduled imports to Salt Lake City are made up elsewhere. For a single-circuit contingency on the 500 kV line section from Garrison to Taft, the adjacent line section reaches 128% of its 944 MVA rating; up from a pre-Project loading of 100% for the same contingency. For contingencies on 500 kV line sections from Colstrip to Broadview and from Broadview to Townsend, the model failed to converge.

Severe Category B undervoltages along the Hiline illustrate that the 161 kV to 230 kV upgrade is not sufficient for the magnitude of new generation added at Colstrip; as was the case for Line 1 of this Project (see Section 3.2.1).

Outages taken on sections of Line 4 are responsible for 33 Category B undervoltage violations on nearby buses in Montana; however, approximately half of these can be eliminated by simultaneously tripping the SVC associated with the out-of-service line. The remaining half of the violations range from 0.94 pu to 0.90 pu.

The most significant improvements brought about by Line 4 occur on the 138 kV system in the PACE area along the Utah-Colorado border. An outage on the 345 kV line from Bonanza to Mona had less effect on the surrounding system with Line 4 in service.

3.3.6 Line 4 Scheduled to Lethbridge

Most of the violations are identical to those found in the Line 4 scheduled to Salt Lake City case above; primarily due to the fact that pre-contingency load flows are not significantly different between the two cases. As was discussed previously for Category A analysis in Section 3.2.6, the schedule is primarily being met by interchanges between the B.C. Hydro and Alberta areas. The effect of contingencies on systems in British Columbia and Alberta were not analyzed due to their remoteness from the Project. The presence of Category A overloads in Canada, and the significant re-adjustment of power flows caused by the Project imply that additional Category B violations developed on systems in Canada for this schedule.

4. DYNAMIC STABILITY ANALYSIS

4.1 Fault Scenarios

Seven fault locations were chosen for stability analysis and are described below. Each fault location listed was run on the indicated model corresponding to heavy flows through the location of the fault. Locations were chosen using engineering judgment based on a combination of proximity to the Project generators, magnitude of load interrupted, and dynamic response to contingencies on sections of the new transmission line options.

4.1.1 Fault Location 1

A double-circuit three-phase fault was applied near the existing Colstrip 500 kV bus, and was cleared by tripping both Project generator tie circuits to the Colstrip 500 kV bus after 3 cycles. Other events include:

- 1000 MW of Project generation was tripped at 3 cycles.
- Post-Project only: Kerr Unit 3 was tripped at 2 seconds.
- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

A double-circuit single-phase-to-ground fault was applied near the existing Colstrip 500 kV bus, and was cleared by tripping both Project generator tie circuits to the Colstrip 500 kV bus after a delayed clearing time of 9 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- 1000 MW of Project generation was tripped at 9 cycles.
- Post-Project only: Fort Peck Unit 1 was tripped at 25 cycles.

The post-Project faults at Location 1 were run on the Line 1 model scheduled to Spokane, which models heavy flows to the Northwest area (WECC Light Summer model), including the additional flows created by the Project. Pre-Project fault scenarios were run on the corresponding base case model.

4.1.2 Fault Location 2

A single-circuit three-phase fault near the existing Colstrip 500 kV bus was applied and subsequently cleared by tripping Circuit 1 of the Colstrip-Broadview 500 kV line after 3 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

A single-circuit single-phase-to-ground fault near the existing Colstrip 500 kV bus was applied and subsequently cleared by tripping Circuit 1 of the Colstrip-Broadview 500 kV line after a delayed clearing time of 9 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

The post-Project faults at Location 2 were run on the Line 2 model scheduled to Spokane, which is based on the WECC Light Summer model. Pre-Project fault scenarios were run on the corresponding base case model.

4.1.3 Fault Location 3

A single-circuit three-phase fault near the existing Garrison 500 kV bus was applied and subsequently cleared by tripping the Garrison-Taft 500 kV line after 3 cycles. For the post-Project scenario, fault clearing was accomplished by tripping the Garrison-Hot Springs 500 kV section of Line 2 after 3 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Garrison 500 kV was tripped at 6.5 cycles.
- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

A single-circuit single-phase-to-ground fault near the existing Garrison 500 kV bus was applied and subsequently cleared by tripping the Garrison-Taft 500 kV line after a delayed clearing time of 9 cycles. For the post-Project scenario, fault clearing was accomplished by tripping the Garrison-Hot Springs 500 kV section of Line 2 after 9 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Garrison 500 kV was tripped at 12.5 cycles.

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

The post-Project faults at Location 3 were run on the Line 2 model scheduled to Spokane, which is based on the WECC Light Summer model. Pre-Project fault scenarios were run on the corresponding base case model.

4.1.4 Fault Location 4

A single-circuit three-phase fault near the new Dillon 500 kV bus was applied and subsequently cleared by tripping the Dillon-Kinport 500 kV section of Line 4 after 3 cycles.

A single-circuit single-phase-to-ground fault near the new Dillon 500 kV bus was applied and subsequently cleared by tripping the Dillon-Kinport 500 kV section of Line 4 after a delayed clearing time of 9 cycles.

The post-Project faults at Location 4 were run on the Line 4 model scheduled to Salt Lake City, which models heavy flows to California and Salt Lake City (new flows to Salt Lake City due to the Project schedule), and moderate flows elsewhere (WECC Heavy Summer).

4.1.5 Fault Location 5

A single-circuit three-phase fault near the existing Colstrip 500 kV bus was applied and subsequently cleared by tripping the Colstrip-Dave Johnston 500 kV section of Line 3 after 3 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Colstrip 500 kV was tripped at 6.5 cycles.
- A reactor at Dave Johnston 500 kV was tripped at 6.5 cycles.

A single-circuit single-phase-to-ground fault near the existing Colstrip 500 kV bus was applied and subsequently cleared by tripping the Colstrip-Dave Johnston 500 kV section of Line 3 after a delayed clearing time of 9 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Colstrip 500 kV was tripped at 12.5 cycles.
- A reactor at Dave Johnston 500 kV was tripped at 12.5 cycles.
- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

The post-Project faults at Location 5 were run on the Line 3 model scheduled to Denver, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Denver created by the Project.

4.1.6 Fault Location 6

A single-circuit three-phase fault near the existing Colstrip 230 kV bus was applied and subsequently cleared by tripping the Colstrip-Fort Peck 230 kV section of Line 4 after 5 cycles. Other events include:

- Fort Peck Unit 1 was tripped at 25 cycles.

A single-circuit single-phase-to-ground fault near the existing Colstrip 230 kV bus was applied and subsequently cleared by tripping the Colstrip-Fort Peck 230 kV section of Line 4 after a delayed clearing time of 25 cycles. Other events include:

- Fort Peck Unit 1 was tripped at 25 cycles.

The post-Project faults at Location 6 were run on the Line 4 model scheduled to Lethbridge, which is based on the WECC Heavy Summer model, and included the additional heavy flows to Lethbridge.

4.1.7 Fault Location 7

A single-circuit three-phase fault near the new Fort Peck 230 kV bus was applied and subsequently cleared by tripping the Colstrip-Fort Peck 230 kV section of Line 4 after 5 cycles. Other events include:

- Fort Peck Unit 1 was tripped at 25 cycles.

A single-circuit single-phase-to-ground fault near the new Fort Peck 230 kV bus was applied and subsequently cleared by tripping the Colstrip-Fort Peck 230 kV section of Line 4 after a delayed clearing time of 25 cycles. Other events include:

- Fort Peck Unit 1 was tripped at 25 cycles.

The post-Project faults at Location 7 were run on the Line 4 model scheduled to Lethbridge, which is based on the WECC Heavy Summer model, and included the additional heavy flows to Lethbridge..

4.2 Dynamic Stability Study Results

4.2.1 Fault Location 1

During initial runs, the Project was shown to have an adverse effect on two other existing generation facilities. For the three-phase fault case, Kerr Unit 3 (70 MW rating) located near Hot Springs became unstable. For the single-line-to-ground case, Fort Peck Unit 1 (62 MW rating) demonstrated instability. The fault scenarios were rerun with the assumption that KERR3 and FT PECK1 units would trip. This was done in order to determine if additional system stability violations occurred with respect to the NERC/WECC criteria.

Both of the three-phase and the pre-Project single-line-to-ground fault analyses demonstrated that the system was transiently stable (with the exception of KERR3 and FT PECK1 as discussed above). The double line outage that was simulated to clear the fault was analyzed using Category "C" stability criteria. For the three-phase and single-line-to-ground fault simulation, the Project did not cause any transient voltage dips exceeding criteria. However, voltages on several 500 kV buses did not remain within 10% of their pre-fault value for the single-line-to-ground case. The worst of these occurred at Townsend 500 kV where voltage stabilized to a new value of 1.30 pu, or 20% above its initial value. The model indicates that pre-Project voltage at Townsend stabilized just 6% above initial conditions for the same fault case.

One frequency dip exceeded criteria during the post-Project single-line-to-ground fault scenario. It occurred on bus COLSTP4 26 kV, where frequency dipped to 58.9 Hz for 18 cycles.

The interruption of Project generation in addition to the two existing Colstrip Units being tripped was detrimental to system stability, as indicated by the loss of two additional units (KERR3 and FT PECK1). Furthermore, instability of Colstrip Unit 2 was observed approximately 4 seconds after the fault for the post-Project single-line-to-ground case. This case does not meet several key stability criteria and is therefore the justification for judging the project to be not viable.

4.2.2 Fault Location 2

The system was shown to be transiently stable for faults at Garrison 500 kV with subsequent clearing of a single Garrison-Taft circuit. Post-transient 500 kV voltage levels were slightly higher with the Project, as opposed to their values pre-Project. No transient voltage violations were observed for pre- or post-Project, three-phase or single-line-to-ground faults at this location. However, voltages on several 500 kV buses in Montana did not remain within 5% of their pre-fault value, averaging 8% above initial voltage levels. This behavior was observed in both the pre- and post-Project scenarios, but does not match historical data for the 500 kV system.

The Project was shown to improve a significant number of frequency dips over the pre-Project case. This is most likely the result of the Project Line 2 in parallel with the contingency. The new parallel circuit provides for improved power flow during and after the fault, thereby reducing the acceleration of nearby machines. As a result, the system is less affected by the disturbance. The addition of the Project improved the worst frequency dip by 0.26 Hz over the pre-Project drop of 59.25 Hz for 16 cycles on COLSTP4 26 kV.

This case does not meet the post-transient voltage deviation criteria, which requires all buses to settle within 5% of their initial voltage levels. A shunt reactor (in addition to the existing 96 MVAR) at the Broadview 500 kV bus may be necessary to maintain post-transient voltage following a disturbance.

4.2.3 Fault Location 3

For Fault Location 3, the system illustrated transiently stable properties. Post-transient 500 kV voltage levels were slightly higher with the Project, as opposed to their pre-Project values. No transient voltage violations occurred pre- or post-Project for any of the fault scenarios. This case meets the key stability criteria; however, momentary frequency fluctuations should be noted.

The worst depression in frequency occurred on FT PECK 1, and was slightly improved by the Project versus the pre-Project dip of 59.29 Hz for 17 cycles. The number of frequency events was generally reduced by the addition of the Project. The Project line section from Garrison to Hot Springs 500 kV allowed more power to flow during and after the fault, resulting in faster settling after the disturbance.

4.2.4 Fault Location 4

Fault scenarios at Location 4 (Kinport 500 kV) resulted in only minor disturbances to the system. Post-transient voltages returned to very near initial values on all buses, and no events exceeding criteria were observed. This case meets all key stability criteria.

4.2.5 Fault Location 5

Faults at Colstrip 500 kV with subsequent clearing of the new Colstrip-Dave Johnston 500 kV resulted in no transient voltage violations. The effect on frequency resembled the post-Project outcome of Locations 3 and 4. The worst frequency dip occurred during a three-phase fault, and was 59.46 Hz for 16 cycles on FT PECK1 13.8 kV. This case meets the key stability criteria; however, momentary frequency fluctuations should be noted.

4.2.6 Fault Location 6

During initial runs, the Project was shown to have an adverse effect on the Fort Peck Unit 1 generator. This unit became unstable for both the three-phase and single-line-to-ground faults. Successive runs were conducted with the assumption that FT PECK1 tripped at 25 cycles, in order to determine if additional system stability violations occurred with respect to the NERC/WECC criteria.

The three-phase fault at Colstrip 230 kV did not cause any transient voltage violations. The single-line-to-ground fault produced three voltage violations: two along the upgraded 230 kV Hiline, and one on a generator bus. Table 8 displays the voltage dips which did not meet criteria.

Table 8 - Transient Voltage Violations Post-Project, SLG Fault, Location 6

Bus Name	kV Class	Initial Voltage (pu)	Percent Dip	Start Time (seconds)	Duration (cycles)
MONTANA1	13.8	1.03	33%	1.4917	5
MTSMALTA	230	1.00	27%	1.8708	25
MTSRICHC	230	1.01	26%	1.9083	20

The worst voltage dip occurred on the MONTANA1 generator bus that experienced voltage of 0.69 pu for a period of 5 cycles. The 230 kV Hiline experienced voltage depressions of 0.73 pu for a duration which exceeded criteria. The worst frequency dip was 59.23 Hz for 23 cycles at the Project generator bus. This case does not meet stability criteria due to the adverse effect on the Fort Peck hydro unit, and the voltage dips shown in Table 8.

4.2.7 Fault Location 7

For Location 7 at Fort Peck 230 kV, the Project was shown to cause instability of the Fort Peck Unit 1 generator. Successive runs were conducted with the assumption that FT PECK1 tripped at 25 cycles, in order to determine if additional system stability violations occurred with respect to the NERC/WECC criteria.

Upon tripping of FT PECK 1, no transient voltage violations occurred for either the three-phase or single-line-to-ground fault scenarios. The worst frequency dip was noted in the three-phase case at FT PECK1 13.8 kV, where frequency dipped to 59.31 Hz for 8 cycles. This case does not meet stability criteria due to the adverse effect on the Fort Peck hydro unit.

5. COST ANALYSIS

Transmission and substation estimated costs for the individual studies are as shown in Table 9. The generation substations do not include any distribution equipment. The estimated costs began at the low side bushings of the GSU transformer and went through to the designated transmission tie-in buses.

Table 9 - Transmission and Substation Costs - Project 1

Line Code	Substation Cost (thousands)	Transmission Cost (thousands)	Total Cost (thousands)
L1	$54,507	$104,739	$159,246
L2	$66,447	$325,720	$392,167
L3	$81,898	$287,027	$368,925
L4	$148,204	$497,030	$645,234

6. VIABILITY ANALYSIS

The feasibility of each transmission line alternative was ascertained given the results of the power flow and dynamic stability analyses. Transmission line options that are considered viable were shown to be acceptable in terms of Category A and dynamic stability criteria. Appropriate project refinements and the mitigation of noted Category B contingencies is expected to be performed with any further project development. Table 10 presents the transmission line options in terms of their viability. A contingency summary table can be found in the appendices for each of the cases determined to be viable.

Table 10 - Viability Summary

Project	Line Code: Description	Schedule	Comments	Viable Project?
Project 1 1000 MW Coal-fired near Colstrip	L1: 230 kV Hiline upgrade	Spokane, Salt Lake City	230 kV Hiline upgrades and existing system insufficient for magnitude of generator output.	No
	L2: 500 kV to Spokane	Spokane	Slight overvoltages can be corrected by adjusting transformer taps.	**Yes**
	L3: 500 kV to Denver	Denver	Meets Criteria.	**Yes**
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
	L4: 500 kV Lethbridge to Salt Lake City	Salt Lake City	3% to 4% reduction in voltage on 500 kV buses: Broadview, Garrison and Bell.	No
		Lethbridge	Heavy loading on existing B.C. to Alberta transfer.	No

As shown in Table 10, Line 1 is considered to be a non-viable alternative due to its significant deficiencies in transporting the new generation. Results from the Category A analysis indicated heavy increased flows on the existing 500 kV corridor which are undesirable.

Line 2 demonstrates sufficient transfer of the new generation scheduled to Spokane. The case met stability criteria and Category A criteria with the exception of slight overvoltages on five buses. These overvoltages could likely be corrected by adjusting appropriate transformer taps near the affected buses.

Line 3 met criteria for schedules to Denver, but did not provide for acceptable transfers to Salt Lake City due to Category A overloads on existing constraint paths. Attempting to correct these overloads to reach the Salt Lake City market is impractical when compared to the design of direct transmission routes to Salt lake City which were studied in Projects 2 and 3.

Heavy loading was observed on existing systems for both of the Line 4 schedules, indicating that Line 4 does not adequately transport the new generation to the delivery points. The primary reason for the deficiency of Line 4 is the lack of strong connections to existing 500 kV systems.

7. CONCLUSIONS

Results from the Project 1 study indicate that the addition of 1000 MW of generation at Colstrip presents challenges related to the export power. Regardless of the scheduled case, a portion of the new generation is exported to the Northwest area along the existing 500 kV corridor from Colstrip to Taft. The quantity and significance of rating and voltage criteria violations consistently outweigh improvements for non-viable cases. The two viable transmission alternatives show that in addition to the radial lines necessary to carry power to remote load centers, transmission improvements in the intended import area may be required to eliminate rating and voltage violations especially during contingency conditions.

Line 1 was demonstrated to be inadequate to support the increased power flows brought about by the Project generator. Dynamic analysis also suggests that the 230 kV upgrade does not significantly improve transient stability along the Hiline. Line 1 is not a viable transmission alternative.

Line 2 provides adequate capacity to support increased generation export to Spokane; however, Category B violations reveal that the heavy flows place added strain on the existing system in the Northwest area. An extension of the Project line from Bell Substation further west or southwest to tie into other existing 500 kV facilities would reduce the number of contingencies requiring mitigation, thereby making Line 2 a viable alternative.

Line 3 to Denver proved to be the best alternative of those studied, strengthening 230 kV systems in Wyoming and Colorado. Violations are mainly concentrated near Daniels Park Substation, and the 161 kV system near the northern Utah-Colorado border. Line 3 is a viable transmission option.

Line 4 alleviated constraints near Bonanza, Utah, and performed well for Category A conditions. However, numerous Category B violations were introduced in the Montana and Northwest areas which are unlikely to be cost-effectively solved. The lack of adequate ties to the existing 500 kV systems makes Line 4 non-viable.